NON-PUBLIC?: N

ACCESSION #: 8810030191
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Palo Verde Unit 1 PAGE: 1 of 7

DOCKET NUMBER: 05000528

TITLE: Reactor Trip Due to Low Steam Generator Level
EVENT DATE: 08/27/88 LER #: 88-024-00 REPORT DATE: 09/26/88

OPERATING MODE: 1 POWER LEVEL: 012

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
NAME: Timothy D. Shriver, Compliance Manger TELEPHONE: 602-393-2521

COMPONENT FAILURE DESCRIPTION:
CAUSE: SYSTEM: COMPONENT: MANUFACTURER:
REPORTABLE TO NPRDS:

SUPPLEMENTAL REPORT EXPECTED: No

ABSTRACT:
At 0826 MST on August 27, 1988, Palo Verde Unit 1 was in Mode 1 (POWER OPERATION) at approximately 12 percent reactor power when a reactor trip occurred due to low level in Steam Generator 1.

The Main Generator was synchronized to the grid at 0816 MST on August 27, 1988 and loaded to approximately 80 MWe. A Reactor Coolant System (RCS) cooldown began and pressurizer level began to decrease. A reactor operator increased dilution flow in an attempt to raise temperature and started the third charging pump in an attempt to increase pressurizer level. Also, Control Element Assembly (CEA) group 5 was withdrawn and the load on the Main Generator was decreased to approximately 45 MWe in an attempt to mitigate the cooldown.

As a result of the dilution and CEA withdrawal, reactor power increased to the point of swapover for the feedwater regulating valves. The isolation valves were shut for the economizer feed regulating valves and all feed flow was lost. The downcomer valves were reopened and feedwater flow reestablished. The event appeared to be stabilized when the "B" Main Feed Pump tripped on high discharge pressure. Steam Generator level decreased and the reactor tripped.

To prevent recurrence, 40AC-9ZZ02 (Conduct, of Shift Operations) will have a requirement added which specifies that a briefing or "tailboard" meeting should be held prior to commencement of all major plant evolutions.

(END OF ABSTRACT)

I. DESCRIPTION OF WHAT OCCURRED:

A. Initial Conditions:

On August 27, 1988, Palo Verde Unit I was in Mode I (POWER OPERATION) at 10 percent reactor power. Preparations were being made to synchronize the main generator (GEN)(TB) to the electrical grid (FK).

B. Report Event Description (Including Dates and Approximate Times of Major Occurrences):

Event Classification:

An event or condition that resulted in manual or automatic actuation of any Engineered Safety Feature (ESF)(JE) including the Reactor Protection System (RPS)(JC).

At 0826 MST on August 27, 1988, Palo Verde Unit I experienced a reactor (RCT) (AC) trip while at approximately 12 percent power.

Prior to the trip, preparations were being made to synchronize the Main Turbine Generator (TG)(TA)(TB) to the electrical grid (FK). Reactor power was stable at 10 percent utilizing the Steam Bypass Control System (SBCS)(JI) with Steam Bypass Control Valve 1001 (SBCV)(PCV)(JI) in manual. The Main Generator (GEN)(TB) output breakers (BKR)(FK) were closed and the generator was synchronized to the electrical grid at 0816 MST on August 27, 1988. The generator was loaded to approximately 80 megawatts electric (MWe) with the SBCS valves (V)(JI) closing as expected during the turbine load increase.

As the TG load was increased, a Reactor Coolant System (RCS)(AB) cooldown began and pressurizer (PZR)(AB) level began to decrease due to the increase in steam flow through the turbine (TRB)(TA). Steam demand increased to a level greater than that of existing reactor power. The Reactor Operator (utility, licensed), who was the primary plant operator, increased the dilution rate from approximately 25 gallons per minute (gpm) to 45 gpm and started the third charging pump (P)(CB) in an attempt to increase the RCS temperature and pressurizer level. With RCS temperature still decreasing, approximately 557 degrees F, the primary plant operator was directed by the Shift Supervisor (SS) (utility, licensed) to begin withdrawing Control Element Assemblies (CEAs)(AA). CEA regulating group 5 was withdrawn from 82 inches withdrawn to 116.5 inches withdrawn. The Reactor Operator (utility, licensed) who was the secondary plant operator reduced turbine load to approximately 45 MWe in an attempt to mitigate the RCS cooldown.

RCS temperature decreased to a low of 548 degrees F. Technical Specification Limiting Condition for Operation (LCO) 3.1.1 4 requires that the RCS lowest operating loop cold leg temperature shall be >/= 552 degrees F. Technical Specification LCO 3.2.6 requires RCS cold leg temperature to be within the Area of Acceptable Operation of Figure 3.2-3. At 0820 MST on August 27, 1988, the ACTION requirements of LCO 3.1.1.4 and LCO 3.2.6 were entered. The RCS cold leg temperature was restored to within acceptable limits and the ACTION requirements of LCO 3.1.1.4 and LCO 3.2.6 were exited. Pressurizer level decreased to ,a low of 22 percent and the ACTION for LCO 3.4.3.1 for a pressurizer minimum steady state water level of >/- 27 percent was entered and exited at 0821 MST on August 27, 1988. However, since LCO 3.4.3.1 only applies during steady state conditions entry into the ACTION was not required.

As a result of the dilution, CEA withdrawal, and reduction of turbine load, reactor power increased to approximately 17 percent. RCS cold temperature increased and pressurizer pressure increased to a maximum pressure of approximately 2370 psia. LCO 3.2.8 maximum allowable pressure is 2300 psia; therefore, at 0822 MST on August 27, 1988 the ACTION requirement was entered and at 0823 MST on August 27, 1988 the ACTION was exited after pressurizer pressure was reduced below 2300 psia.

When reactor power increased to approximately 17 percent the Feedwater Control System (FWCS)(JK) swapover occurred. The swapover is when feedwater supplied to the steam generator (SG) (AB) is automatically swapped from the downcomer feed regulating valve (FCV)(JK) to the economizer feed regulating valve (FCV)(JK). Since he economizer isolation valves (ISV)(JK) were still shut, in accordance with an approved General Operating Procedure, there was no feedwater flowpath to either steam generator. The economizer isolation valves are maintained shut until after the generator is synchronized and the feedwater lines are wa med up to > 200 degrees F. The pre-warming requirement was added to the procedure for Cycle 2 in Unit I to minimize the effects of reactivity changes when operating with a positive Moderator Temperature Coefficient (MTC).

The third control room operator (utility, licensed) and the secondary plant operator took the downcomer regulating valve controllers for both steam generators to manual and restored feedwater flow to the steam generator. At this time the transient appeared to be stabilized with steam generator levels at approximately 20 percent narrow range. However,the FWCS increased the "B" Main Feedwater Pump (MFP)(P)(JK) speed and the MFP tripped

on high discharge pressure at 0824 MST on August 27, 1988. The "B" MFP tripped on high discharge pressure due to high pump speed with the downcomer feed valves insufficiently open.

The third control room operator reset the "A" MFP, but could not get the pump speed to increase. He observed that the pump was in manual and the high and low pressure stop valves had opened indicating the pump had reset. He attempted to increase feed pump speed manually using the speed adjust potentiometer, but no increase in speed was observed. During the investigation of this event it was determined that the operator had not placed the speed adjust potentiometer in a complete counter-clockwise rotated position before attempting to increase pump speed. Not doing so prevented any speed demand signal from getting to the pump turbine governor valves. After attempts to start the "A" MFP, the third control room operator attempted to restart the "B" MFP. The "B" MFP was reset and

the miniflow was verified open as well as pump control being in manual. The operator was attempting to set the speed potentiometer to zero when the reactor tripped.

The secondary plant operator started the "B" essential auxiliary feedpump (P)(BA) to provide some feedwater flow. Steam generator levels continued to decrease due to insufficient feedwater and the reactor tripped on Steam Generator -1 low level at 0826 MST on August 27, 1988.

Following the trip, the operators monitored safety function while the Control Room Supervisor (CRS)(utility, licensed) performed an event diagnosis in accordance with approved procedure 41EP-lZZ01(Emergency Operations). The event was properly diagnosed as an uncomplicated trip and the appropriate recovery procedure 41RO-IZZ01 (Reactor Trip) was utilized to stabilize the plant in Mode 3 (HOT STANDBY). The plant was stabilized in Mode 3 at approximately 0900 MST on August 27, 1988.

C. Status of structures, systems, or components that were inoperable at the start of the event that contributed to the event:

Not applicable - no structures, systems, or components were inoperable at the start of the event that contributed to the event.

D. Cause of each component or system failure, if known:

Not applicable - no component or system failures were involved.

E. Failure mode, mechanism, and effect of each failed component, if known:

Not applicable - no failed components were involved.

F. For failures of components with multiple functions, list of systems or secondary functions, that were also affected:

Not applicable - no failed components were involved.

G. For failure that rendered a train of a safety system inoperable, estimated time elapsed from the discovery of the failure until the rain was returned to service:

Not applicable - no safety systems were rendered inoperable.

H. Method of discovery of each component or system failure or procedural error:

Not applicable - no component or system failures or procedural errors were involved.

I. Cause of Event:

The root cause of the event was a cognitive personnel error on the part of the Shift Supervisor (utility, licensed) in that he did not provide adequate direction in the method to mitigate the cooldown. The control board operator (utility, licensed) attempted to mitigate the cooldown by increasing the dilution rate. The SS directed CEAs to be withdrawn and generator load be decreased. While taking the actions was correct, the magnitude of these actions was more than was required to terminate the overcooling. This subsequently resulted in an overcorrection and resultant temperature and pressure increase. The SS should have provided specific direction to control board operators (utility, licensed) prior to generator synchronization through the use of a tailboard meeting. A normal crew shift turnover brief was held but specifics regarding control of temperature and power during the generator synchronization were not discussed. No action plans were formulated for control of any transients which might develop. The CRS did not review the approved operating procedures 41OP-IMBOI (Main Generation and Excitation) or 41OP-lZZ04 (Plant Startup Mode 2 to Mode 1) with the control room staff prior to the plant evolution.

A review of procedures used during the event identified that 41OP-lZZ04 directs that the generator be placed in service per 41OP-lMB01. 41OP-lMB01 is typically used by the operator performing the synchronization. However, most of the precautionary information regarding synchronizing the main generator is contained in 41OP-IZZ04 which is typically used by the control room supervisor (utility, licensed).

A review of 41OP-lFT02 (System Operating Procedure for the "B" MFP) was conducted to determine the reason for the inability to obtain feedwater flow from the "A" MFP and to restart the "B" MFP. The review determined that section 6.3.2 requires that prior to resetting the feedwater pump turbine, the manual Speed Controller Potentiometer must be set to zero (i.e., full counterclockwise). Review of the circuit logic indicates that the manual Speed Controller Potentiometer must be taken to zero before the interlock holding the reset solenoid open can be satisfied. It is still possible to have the stop valves and the miniflow valves open with the Speed Controller Potentiometer at greater than zero, but the control valves will not open to admit steam to the feedwater pump turbine. Therefore, unless the Speed Controller Potentiometer is in the full counterclockwise position, the feedwater pump turbine cannot be brought up to speed. The operator was aware of this requirement when attempting to start "A" MFP. The operator thought that the speed potentiometer had been correctly set to zero since the pump was in hot standby. However, he did not check that the potentiometer had been zeroed. The operator then attempted to zero the "B" MFP potentiometer when the reactor tripped.

It should be noted the operating procedure for the MFP's does not zero the speed potentiometer when placing the pumps in hot standby. This is done in the section for MFP startup.

There were no unusual characteristics of the work location that directly contributed to the event.

J. Safety System Response:

Other than the reactor trip, no manually or automatically initiated safety system responses were received and none were necessary.

K. Failed Component Information-

Not applicable - no failed components were involved.

II. ASSESSMENT OF THE SAFETY CONSEQUENCES AND IMPLICATIONS OF THIS EVENT:

As described above, the reactor tripped as designed and all safety responses necessary to place the plant in a stable condition worked properly. There were no ESF actuations and none were required. Therefore, this event had no impact on the health and safety of the public.

III. CORRECTIVE ACTIONS:

A. Immediate:

The "B" MFP high discharge pressure switches (PS)(JK) were verified to be properly calibrated. A night order was prepared outlining actions that should be taken to minimize any transients when placing the Main Turbine on line.

B. Action to Prevent Recurrence:

A requirement will be added to 40AC-9ZZ02 (Conduct of Shift Operations) which specifies that a briefing or "tailboard" meeting should be held prior to commencement of all major plant evolutions. An evaluation will be performed of the effectiveness of crew teamwork in mitigating the transient. Also, various operating procedures pertinent to this event will be evaluated and revised as necessary to preclude recurrence of this event.

IV. PREVIOUS SIMILAR EVENTS:

Other events have been reported which involved reactor trips on low steam generator level. However, no other events have been reported which involved a similar sequence of events as described in this report.

Arizona Nuclear Power Project
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192-00413-JGH/TDS/JEM
September 26, 1988

U. S. Nuclear Regulatory Commission
NRC Document Control Desk
Washington, D.C. 20555

Dear Sirs:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Unit I
Docket No. STN 50-528 (License No. NPF-41)
Licensee Event Report 88-024-00
File: 88-020-404

Attached please find Licensee Event Report (LER) No. 88-024-00 prepared and submitted pursuant to 10CFR 50.73. In accordance with 1OCFR 50.73(d), we are herewith forwarding a copy of the LER to the Regional Administrator of the Region V office.

If you have any questions, please contact T. D. Shriver, Compliance Manager at (602) 393-2521.

Very truly yours,

J. G. Haynes
Vice President
Nuclear Production

JGH/TDS/JEM/kj

Attachment

cc: D. B. Karner (all w/a)
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ACCESSION #: 8810030201